

DRA's Responses to the Questions on 33% RPS Implementation Analysis
Preliminary Results Report

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1. Has this study produced information that is useful for planning or policymaking purposes?

Yes, the 33% RPS Implementation Analysis Preliminary Results report (IAPR) has produced information that is useful for planning and policymaking purposes. DRA believes the following finding is especially useful:

- **The IAPR states plainly, “the pace of required renewable resource development is so rapid compared to load growth that a substantial surplus of [conventional] capacity is all but unavoidable.”¹ However, this surplus is only temporary because “the pace” of the current RPS, as the IAPR puts it, is partly the result of LSE’s delay in meeting their obligations earlier in the mandate period. Similarly, this surplus will further be absorbed by California’s high Resource Adequacy (RA) standards and ever increasing search for a multi-year RA obligations and long-term planning adjustments. The more appropriate issue concerning the surplus is not whether it exists at all. Given that the RPS program is a legislative mandate, surpluses are inevitable. The more appropriate issues is at what level of stranded costs and to what extent is it reasonable for ratepayers to bear a more rapid transition from conventional resources to RPS compliance. This should be considered by policy makers and procurement planners.**

Would a more detailed study provide additional value for either planning or policy purposes, or both?

This depends on what planners or policy makers are seeking. DRA recommends that rather than performing a more detailed study, a “refresh” of the data and a rework of the scenarios would provide the biggest bang for the buck. Energy Division (ED) is already planning a revision to this report by the end of 2009.² When doing this final revision, an update of the study with additional new market data from the CPUC ED Database and RETI, as it becomes available, would provide additional value infusing new data points that reflect the latest project info and market costs.

In addition, the study should consider tweaks to the primary scenarios used for analysis. The primary scenarios become much more important as the results of this study and others (e.g., LTPP System Planning, and CAISO 33% RPS Integration Study) become integrated. Having scenarios that share common assumptions and basic design will facilitate easier integration of the studies. For example, the 33% Reference Case in the IAPR should mean the same thing as the LCBF Renewables Scenario in the LTPP Straw Proposal. Likewise, the High DG Case scenario in the IAPR should represent the LTPP Transmission-constrained scenario. These scenarios should likewise flow in a similar manner to the CAISO 33% RPS Integration study.

¹ IAPR, p. 29.

² IAPR, p. 11.

As for changes in the scenarios, two changes to consider would be to drop the All Gas Scenario and modify the High Out-of-State Delivered Scenario. The All Gas Scenario represents a scenario that would be considered illegal given California has a 20% RPS mandate. To waste modeling resources on a future which cannot happen, does not seem prudent and provides little value.

The High Out-of-State Delivered Case, which assumes the construction of new multi-state transmission to bring resources from Wyoming to California also seems extremely unlikely. What would be much more informative and reflect the real-world would be to change that scenario to represent out-of-state renewables that are delivered by firming and shaping. The most recent ED RPS Update reports that in 2009, 25% of the RPS contracts approved are for out-of-state resources (397 MW of 1,574 MW).³ Likewise, the same report specifies that over the 2003-2008 timeframe 90% of the new capacity came from wind and nearly half of the new wind capacity was developed out of state.⁴ The point is that large quantities of out-of-state resources are being contracted and coming on-line without new multi-state transmission lines. These resources are being delivered through firming and shaping arrangements. The High Out-of-State Delivered case should be changed to reflect reality and also try to capture the real costs of firming and shaping to show how that case compares to the other scenarios.

2. Do you agree with the study's general conclusions that (a) the 2020 timeline is aggressive, (b) the state's process reforms are likely to speed the timeline, (c) the state faces risks that are outside of its control that can affect the state's ability to achieve 33% on a given timeline, (d) the rate impacts of 33% relative to 20% are in the 3-10% range, and (e) there are tradeoffs among the different strategies for achieving 33%?

(a) DRA agrees that the 2020 timeline is aggressive, but so was shifting the 20% by 2017 target to 20% by 2010 with barely seven years to get to 2010. DRA recommends that the 33% RPS requirement should allow flexibility in meeting annual RPS milestones to account for unexpected challenges. Flexible compliance will help mitigate stranded investment in conventional generation resulting from the transition from conventional resources to more renewables as well as reduce regulatory pressure.

(b) It is unlikely that California can achieve a 33% RPS any earlier than 2020. It is difficult to understand how the 2020 timeline could be further expedited, regardless of any process reform. However, DRA is hopeful that these process reforms will reduce delays.

(c) Yes, resources are limited and economic conditions change all the time; these conditions among other are beyond the state's control, not to mention factors

³ CPUC RPS Status Report Q3 2009, p. 4.
http://www.cpuc.ca.gov/NR/rdonlyres/EBEEB616-817C-4FF6-8C07-2604CF7DDC43/0/Third_Quarter_2009_RPS_Legislative_Report_2.pdf

⁴ *Id.*, p. 8.

such as regulatory flux in neighboring states whose renewable resources are currently counted in California's RPS program.

(d) Probably, DRA has not conducted an independent assessment of these costs, but the IARP figures, given their assumptions about the potential technological combinations, do not seem unreasonable.

(e) Yes, DRA agrees. The IARP has drawn appropriate conclusion from this study.

3. The goal of the resource ranking and selection process was to produce "plausible", but not necessarily "optimal" portfolios for achieving a 33% RPS by 2020. Under the assumption that 33% itself is plausible, do you believe the resource mixes that are modeled are "plausible"? If not, what would a plausible resource mix be? How would you alter the modeling process to produce plausible portfolios?

As mentioned below, DRA believes the estimates of future central solar thermal plant capacity are optimistic. A plausible resource mix would include a lower percentage of this resource, and a higher percentage of wind energy. However, the increased cost for resource adequacy and system stability should be considered at high to very high wind penetrations.

4. The 33% RPS Reference Case relies heavily on resources that have been selected through IOU solicitations and are therefore represented in the CPUC ED RPS project database. Do you agree with the methodology for treating CPUC Database resources (i.e., treating their costs as "sunk" for ranking purposes)? If not, what would be an alternative method of incorporating those projects?

The methodology used appears to be the best possible from the available information.

5. After exhausting the CPUC ED Database projects, the model fills the remaining need using RETI pre-ID or proxy projects. Do you agree that RETI is a reasonable source of additional project availability and performance data?

The CPUC ED Database is the best source of information for project availability and performance data. DRA is not aware of any other database that would be preferable over RETI. Certainly the RETI database possesses a level of credibility. The RETI pre-ID data should be given more weight than the RETI proxy projects. As RETI phases out the proxy projects from their database, so too should be the best source.

6. In addition, the model relies on out-of-state resource availability and performance data from E3's GHG Calculator (the original data came from NREL and EIA). Do you agree that out-of-state projects are characterized accurately and are a reasonable source of energy to meet California's RPS needs?

The estimates of out-of-state potential appear to be reasonable and DRA agrees that these projects can be a reasonable source of energy to meet California's RPS needs. They show the "high out-of-state delivered" case having a lower cost of energy than the other options, but a cost that is virtually the same as the "high-wind" case.

7. The final source of project data is the original estimates of DG potential developed by E3 and Black & Veatch. Do you agree that these estimates are plausible and a reasonable source of information for a study of this nature?

These estimates seem plausible, as they indicate a high theoretical potential for DG (mostly PV), but at a cost higher than the other scenarios.

8. The 33% RPS Reference Case relies very heavily on solar thermal resources, which are largely untested at utility scale. Do you believe it is reasonable to rely on 7200 MW of solar thermal resources coming online by 2020?

Highly unlikely, DRA does not believe it is reasonable to assume that 7,200 MW of solar thermal resources will come online by 2020. Since 2004, 11 solar thermal resources totaling more than 4,600 MW have been brought before the CPUC. Power Purchase Agreements for these resources have been executed with 9 different developers in a variety of locations across the state. To date, none of these resources has been successfully developed, two have failed outright, and most have required contract amendments allowing for delays and price hikes.⁵ Central station solar thermal resources have been the least viable to date of all RPS eligible technologies.

Recognizing that these solar thermal resources may play a vital role in delivering cost-competitive on-peak renewable energy, the IOUs and CPUC have, at least for the past few years, done everything to facilitate the success of these developments; however, they simply are not materializing. Therefore, it would be a mistake for the CPUC to depend on new solar thermal resources until the existing developments prove viable.

As an alternative, more realistic assumption, DRA recommends the IARP assume 50% of the existing solar thermal resource will materialize. DRA does not believe that more than 2,300 MW of solar thermal resources will be developed by 2020.

9. The High Wind Case relies on substantial quantities of in-state wind resources. However, many of the projects identified are "proxy" projects from the RETI database, rather than projects that have been identified by developers. In addition, solar projects are heavily represented in the CPUC Database. Given the model's preference for wind resources due to cost, why do you think that more wind projects haven't been selected for development through IOU solicitations?

⁵ Energy Division's RPS Project Status Table 3rd Quarter 2009 (publicly available at <http://www.cpuc.ca.gov/PUC/energy/Renewables/>)

As mentioned in question #1, there have been many out-of-state wind projects selected through the IOUs solicitations and through bilateral contracting. There are a number of reasons why more in-state wind projects have not been selected. One reason could be that even though IOUs select bids using a Least Cost Best Fit methodology, the IOUs still have great latitude on which projects are ultimately shortlisted. Second, the permitting requirements in other Western states are far easier and take significantly less time than those in California. A third reason may have to do with regulatory certainty. Specifically, the full build out of the Tehachapi Transmission line could ultimately enable up to 4500 MW of California wind capacity only 700 MW (Tehachapi 1-3) is certain. IPPs looking to develop in Tehachapi may be waiting to see the outcome of the Tehachapi 4-11 proceeding.

As a member of the IOU Procurement Review Groups, DRA monitors most IOU renewable procurement activities, including their competitive renewable solicitations. Based on this experience, DRA observes that a limited number of in-state wind resources (relative to solar resources and out-of-state wind resources) have been bid into the solicitations. In addition, the utility bid ranking systems penalize in-state wind compared to all other resources due to its poor hourly fit to utility loads. DRA looks forward to hearing from other parties who may have additional insight into why more in-state wind resources are not being offered. Generally speaking, DRA supports in-state wind developments as they are frequently cost-competitive.

In addition, as the Commission has recently put additional focus on the Imperial Valley renewable projects and bids in the IOU's solicitations, the Commission could also put additional focus on California wind projects.

10 The High Out-of-State case relies on substantial quantities of wind from Wyoming and geothermal from northern Nevada. Do you think it is plausible to rely on these resources coming online by 2020, including transmission to California? Are there other challenges with out-of-state resources, such as limited availability of firming and shaping capacity?

As specified in question 1, this scenario is not plausible. Though a study of this scenario may be appropriate for transmission planners attempting to study potential connections to these remote areas, the CPUC should be focusing more on likely scenarios that we have more control over. Again what would be more plausible would be to model a High Out-of-State Delivered by firming and shaping. This would allow the costs of firming and shaping to be captured and compared with the other scenarios. Whether this cost will be significant is not yet clear, as Power Purchase Agreements are now being approved without precisely defined costs for firming and shaping. Current activity in the Legislature and the Commission regarding the allowance of tradable renewable energy credits could, in theory, reduce or eliminate these costs.

11 The High DG case relies on 15,000 MW of in-state solar PV resources. Do you believe it is plausible to develop PV resources on this scale by 2020? Are there any operational issues associated with relying on this quantity of PV resources that the study did not consider? Are the PV potential estimates reasonable and plausible?

The physical PV potential in the state is sufficient to supply 15,000 MW, and given the explosion in world PV cell production capacity in the last few years (largely promoted at first by Japanese and European programs, and now the California Solar Initiative) the installation of this amount of PV by 2020 seems possible. Although the CSI program is making steady process, it would only account for a small percentage of 15,000 MWs. The operational issues seem surmountable, but may require limitations on PV installed capacity in some places, or electric distribution system upgrades. Some present distribution protection systems may need to be changed to allow “back-flow” of electricity.

12 All of the cases assume that new transmission is required to deliver most (but not all) of the RPS resources to load. Do you agree that new transmission is needed in most cases, or are new resources likely to be able to make more use of the existing transmission system, e.g., by displacing existing fossil resources in the hourly dispatch?

It is a reasonable assumption that some new transmission lines will be needed and built, though the question is what number will be needed. What is sure is that any new transmission capacity will be added in an incremental fashion. The displacing of existing resources will occur over time, the displacement will not occur at the flip of a switch.

In certain scenarios, such as replacing out-of-state coal energy with in-state base-load renewables, transmission needs could be reduced by renewables. However, it is difficult to answer this question accurately without the use of hourly production models of generation, transmission, and use. If the old generation replaced is primarily in-state and the new renewable generation is out-of-state it is probable that new transmission will be needed, since most of the transmission crossing California’s borders brings energy into the state. In addition, variable (intermittent) renewables are relatively less economic the further they are from the electric load, as they may result in a low load factor on transmission lines sized for the maximum, not the average, power carried.

13 Do you believe it would be an improvement to the study methodology to account for the ability of the existing transmission system to accommodate new renewable resources? What would be a good method of doing this?

Yes, though this would require an integration study. The Commission should rely on the CAISO and Transmission developers and stakeholders to lead this effort. There are a number of models that do generation modeling well and there are a number of models that handle transmission modeling well.

14. Do you believe that a detailed mapping of 33% RPS resources is valuable for transmission and procurement planning? Why or why not?

Yes, since the cost of mapping now will certainly be a tiny fraction of the future costs of making errors now in resource location or transmission construction. RETI is taking the lead on this effort.

15. Please include any additional comments on the report, including the implementation timelines and assumptions used to build the implementation timelines.

DRA finds the results of the IAPR's "Low-Load" sensitivity analysis compelling.⁶ For this analysis, the IAPR assumes that electric load growth will be reduced through effective demand reduction policies and programs. As the IAPR states, reducing load growth should result in a reduction in the incremental cost of achieving 33%. However, the model actually yields counterintuitive results. Since the analysis anticipates a need for new capacity resources in the near-term, followed by renewable energy resources and demand reduction in the mid- to long-term, "a substantial surplus of capacity is all but unavoidable."⁷ Table 8 of IAPR shows that because of this interplay between demand reduction and meeting near-term capacity needs, the extra electricity expenditures required to meet the 33% Reference Case in the "Low-Load" case will be \$400 million.

Ratepayers should not have to pay for this "surplus capacity" if they can be avoided or reduced by adequate planning and transitioning (e.g., if its costs are duplicative of other programs). Instead, the pace of renewable development and the need for new capacity additions should be coordinated with planned reductions in demand. The IAPR correctly concludes the implications of this finding: "an integrated approach is needed to ensure that policy goals result in a resource plan that effectively furthers the important, underlying policy objectives and produces an efficiently integrated electricity system at an acceptable cost."⁸ DRA will address its concerns and offer its suggestions in R.08-02-007 where Long Term Procurement Planning Standards should be calibrated to effectively manage the risks identified by the IAPR's Low-Load sensitivity analysis.

The Executive Summary suggests that, using current RPS contracts as an example, in-state economic development and market transformation are the primary policy objectives.⁹ This is a misleading statement and should be removed. As stated earlier, many out-of-state RPS contracts are being approved and coming on-line (i.e., 25% of the RPS contracts approved in 2009 are for out-of-state resources and over the 2003-2008 timeframe, 90% of the new capacity came from wind and nearly half of the new wind capacity was developed out of state). DRA would suggest that using the current RPS contracts as an example, Least Cost Best Fit (LCBF) contract selection and RPS-eligible resources, are the two primary

⁶ IAPR, pp. 27-31.

⁷ IAPR, p. 29.

⁸ IAPR, p. 29.

⁹ IAPR, p. 11.

policy objectives. The Utilities use the LCBF methodology for ranking RPS contracts and the Commission has approved all RPS contracts that meet the CEC RPS deliverability rules.